IN THE SPECIFICATION:

Please amend paragraphs [0008], [0010], [0013], [0017], [0022], [0033], [0034], [0035], [0036], [0037], [0038], [0039], [0040], [0041], [0044], [0045], [0047], [0049], [0050], and [0051] of the specification as follows:

[0008] More recently, sealing arrangements between tubulars provide a metal to metal conductive contact between the joints. In one such system, for example, electrically conductive coils are positioned within ferrite troughs in each end of the drill pipes. The coils are connected by a sheathed coaxial cable. When a varying current is applied to one coil, a varying magnetic field is produced and captured in the ferrite trough and ~~includes~~ <u>induces</u> a similar field in an adjacent trough of a connected pipe. The coupling field thus produced has sufficient energy to deliver an electrical signal along the coaxial cable to the next coil, across the next joint, and so on along multiple lengths of drill pipe. Amplifying electronics are provided in subs that are positioned periodically along the string in order to restore and boost the signal and send it to the surface or to subsurface sensors and other equipment as required. Using this type of wired pipe, components can be powered from the surface of the well via the pipe.

[0010] Drilling jars have long been known in the field of well drilling equipment. A drilling jar is a tool employed when either drilling or production equipment has become stuck to such a degree that it cannot be readily dislodged from the wellbore. The drilling jar is normally placed in the pipe string in the region of the stuck object and allows an operator at the surface to deliver a series of impact blows to the drill string by manipulation of the drill string. Hopefully, these impact blows to the drill string ~~dislodging~~ <u>dislodge</u> the stuck object and permit continued operation.

[0013] An example of a mechanically tripped hydraulic jar is shown in Figure 1. The jar 100 includes a housing 105 and a central mandrel 110 having an internal bore. The mandrel moves axially in relation to the housing and the mandrel is threadedly attached to the drill string above (not shown) at a threaded joint 115. At a predetermined time measured by the flow of fluid through an orifice <u>(not shown)</u> in the tool 100, potential force applied to the mandrel from the surface is released and a hammer 120 formed on the mandrel 110 strikes a shoulder 125 creating a jarring

effect on the housing 105 and the drill string therebelow (not shown) that is connected to the housing at a threaded connection 130.

[0017] The present invention generally provides a downhole tool with an improved means of transmitting data to and from the tool through the use of wired pipe capable of transmitting a signal and /or power between the surface of the well and any components in a tubular string. In one aspect, a downhole tool includes a body, and a mandrel disposed in the body and movable in relation to the body. A ~~conducive~~ conductive wire runs the length of the body and permits signals and /or power to be transmitted though the body as the tool changes its length.

[0022] Figures 3A and 3B are section views of a jar having an inductive connection means between the jar housing and a central mandrel[[;]] .

[0033] Figure 2A illustrates a ~~jar~~ tool (jar) 100 in a retracted position and Figure 2B shows the jar 100 in an extended position. The jar 100 includes a coiled spring 135 having a data wire (not shown) disposed in an interior thereof, running from a first end 140 to a second end 145 of the tool 100. The coiled spring and data wire ~~is~~ 135 are of a length to compensate for relative axial motion as the tool 100 is operated in a wellbore. In the embodiment of Figures 2A and 2B, the coil spring and data wire 135 are disposed around an outer diameter of ~~the~~ a mandrel 110 to minimize interference with the bore of the tool 100. In order to install the jar 100 in a drill string (not shown), each end of the jar 100 includes an inductive coupling (not shown) ensuring that a signal reaching the jar 100 from above will be carried through the tool 100 to the drill string and any component therebelow. The induction couplings, because of their design, permit rotation during installation of the tool 100.

[0034] In another embodiment, a series of coils at the end of one of the jar components communicates with a coil in another jar component as the two move axially in relation to each other. Figure 3A show a jar 100 with a housing 105 having a number of radial coils 150 disposed on an inside surface thereof. Each of the coils 150 is powered with a conductor 153 running to one end of the tool 100 where it is attached to the drill string. A single coil 155 is formed on an outer surface of a mandrel 110 and is wired via conductor 154 to an opposing end of the tool 100. The coils 150, 155 are constructed and arranged to remain in close proximity to each

other as the tool 100 operates and as the mandrel 110 moves axially in relation to the housing 105.

[0035] In Figure 3A, a single coil 150 is opposite mandrel coil 155. In Figure 3B, a view of the tool 100 after the mandrel 110 has moved, the coil 155 is partly adjacent two of the coils 150, but close enough for a signal to pass between the housing 105 and the mandrel 110. In an alternative embodiment, the multiple coils 150 cold be formed on the mandrel 110 and the single coil 155 could be placed on the housing 105.

[0036] In another embodiment, a signal is transmitted from a first to a second end of the tool through the use of short distance, electromagnetic (EM) technology. Figure 4 is a section view of a jar 100 with ~~E.M.~~ EM subs 160 placed above and below the jar 100. The EM subs 160 can be connected to wired drill pipe by induction couplings (not shown) or any other means. The subs 160 can be battery powered and contain all means for wireless transmission, including a microprocessor (not shown). Using the ~~E.M.~~ EM subs 160, data can be transferred around the jar 100 without the need for a wire running through the jar 100. By using this arrangement, a standard jar can be used without any modification and the relative axial motion between the mandrel 110 and the housing 105 is not a factor. This arrangement could be used for any type of downhole tool to avoid a wire member in a component relying upon relative axial or rotational motion. Also, because of the short transmission distance, the power requirements for the transmitter in the subs 160 is minimal.

[0037] In other embodiments, various operational aspects of a jar in a drill string of wired pipe can be monitored and /or manipulated. For example, Figures 5A and 5B are section views of a jar 100 illustrating a means of adjusting the magnitude of jarring impact. A pressure sensor (not shown) in a high pressure chamber (not shown) of the jar 100 can be used to determine the exact amount of overpull placed upon the jar 100 from the surface of the well. An accelerometer (not shown) can be used to measure the actual impact of the hammer 120 against the shoulder 125 after each blow is delivered. This information can then be used by an operator along with a jar placement program to optimize the amount of overpull and adjust the free stroke length 165 of the jar 100 to maximize the impact. The stroke length 165 is adjustable by rotating the hammer 120 around a threaded portion 175 of the mandrel

110, thus moving the hammer 120 closer or further from the shoulder 125. By changing the free stroke length 165 between the hammer 120 and the shoulder 125, the distance the hammer 120 travels can be optimized to deliver the greatest impact force. For example, adjusting the stroke length 165 would allow the impact to occur when the hammer 120 has reached its maximum velocity. The free stroke length 165 may need to be longer or shorter depending on the amount of pipe stretch, hole drag, etc. In conventional jars, the amount of free stroke can only be set at one distance and therefore the hammer can lose velocity or not reach its full velocity before impact. An actuator, like a battery operated motor might be used in the tool 100 to cause the movement of the hammer 120 along the threaded portion 175 of the mandrel 110.

[0038] In another embodiment, the operation of a jar can be controlled in a manner that can render the tool inoperable during certain times of operation. Figures 6A and 6B are section views of a tool 100 showing a solenoid 180 located in the bore of the mandrel 110. The purpose of the solenoid 180 is to stop metering flow in the jar 100 until a signal is received to allow the jar 100 to meter fluid as normal. In Figure 6A the solenoid 180 is in an open position permitting fluid communication between a low pressure chamber 185 and a high pressure chamber 190, through a metering orifice 195 and a fluid path 197. In a closed position, (Figure 6B), solenoid 180 blocks the flow of internal fluid between the chambers 185, 190 and does not allow the mandrel 110 to move to fire the jar 100. When in the position of Figure 6B, the jar 100 can operate like a stiff drill string member when not needed. This makes running in much easier and safer by not having to contend with accidental jarring. This also overcomes problems associated with other jars that have a threshold overpull that must be overcome to jar. Using this arrangement, the jar 100 works through a full range of overpulls without any minimum overpull requirements. Also, by making the solenoid 180 assume the “closed” position when not connected to a power line, the requirement for a safety clamp can be eliminated. This feature is especially useful in horizontal drilling applications where external forces can cause a jar to operate accidentally. As shown in the Figures, the solenoid is typically powered by a battery 198 which is controlled by a line 199.

[0039] In another embodiment, the timing of operation of a jar can be adjusted by changing the size of an orifice in the jar through which fluid is metered. Figures 7A

and 7B are section views of a jar 100 with an orifice 200 disposed therein. A solenoid 180 is placed in an internal piston 205 of the jar 100 and a battery 210 and microprocessor 215 are installed adjacent the solenoid 180. By moving the solenoid 180 between a first and second positions, the relative size of the orifice 200 can be changed, resulting in a change in the time needed for the jar 100 to operate. For example, in Figure 7A with the solenoid 180 holding a plug 217 in a retracted position, the orifice 200 is a first size and in Figure 7B with the solenoid 180 holding the plug 217 in an extended position, the orifice 200 is a second, smaller size. Alternatively, the orifice 200 can be completely closed. With the ability to change the amount of time between the start of overpull and the actual firing of the jar 100, the number and magnitude of the blows can be affected. For example, by allowing more time before firing, the operator could be sure that the maximum overpull was being applied at the jar 100 and that the overpull is not being diminished by hole drag or other hole problems. By changing the timing to a faster firing time, the operator can get more hits in a given amount of time.

[0040] In still another embodiment, a jar 100 can be converted to operate like a bumper sub during operation. A bumper sub is a shock absorber-like device in a drill string that compensates for jarring that takes place as a drill bit moves along and forms a borehole in the earth. In the embodiment of Figures 8A and 8B, a section view of a jar 100, a solenoid 180 is actuated to open a relatively large spring-loaded valve 220 (Figure 8B) that allows internal fluid to freely pass through the tool 100. Since no internal pressure can build up, the tool 100 opens and closes freely. This feature provides the usefulness of a bumper sub when needed during drilling.

[0041] Figure 9 is a section view of an electronically actuated jar 100. Because data can be quickly transmitted to the jar 100 using the wired pipe means discussed herein, a jar 100 can be provided and equipped with an electronically controlled release mechanism. The release mechanism could be mechanical or electromagnetic. This mechanism would hold the jar in the neutral position until a signal to fire is received. The electronic actuation means eliminates the use of fluid metering to time the firing of the jar. By using an electronically actuated jar, many of the problems associated with hydraulic jars could be eliminated. This would eliminate bleed-off from the metering of hydraulic fluid and would allow the jar to fire only when the operator is ready for it to actuate. Also, because the jar would be

mechanically locked at all times, the need for safety clamps and running procedures would be eliminated.

[0044] Figure 11A and 11B are section views of a wellbore showing a rotatable steering apparatus 10 disposed on a drill string 75. The apparatus 10 includes a drill bit 78 or a component adjacent the drill bit 78 in the drill~~ing~~ string 75 that includes non-rotating, radially outwardly extending pads 85 which can be actuated to extend out against the borehole or in some cases, the casing 87 of a well and urge the rotating drill bit 78 in an opposing direction. Using rotatable steering, wellbores can be formed and deviated in a particular direction to more fully and efficiently access formations in the earth. In Figure 11A, the drill bit 78 is coaxially disposed in the wellbore. In Figure 11B, the drill bit 78 has been urged out of a coaxial relationship with the wellbore by the pad 85. Typically, a rotatable steering apparatus 10 includes at least three extendable pads 85 and technology exists today to control the pads 85 by means of pulse signals which are transmitted typically from a MWD device 90 disposed in the drill string 75 thereabove. By sending pulse signals similar to those described herein, the MWD device 90 can determine which of the various pads 85 of the rotatable steering apparatus 10 are extended and thereby determine the direction of the drill bit 78. As stated herein, only a limited amount of information can be transmitted using pulse signals and the rotatable steering ~~device~~ apparatus 10 must necessarily ~~has~~ have its own source of power to actuate the pads 85. Typically, an on-board battery supplies the power. Rotary steerable drilling is described in U.S. Patent Nos. 5,553,679, 5,706,905 and 5,520,255 and those patents are incorporated herein by reference in their entirety.

[0045] Using emerging technology whereby signals and /or power is provided in the drill string 75, the rotatable drilling apparatus 10 can be controlled much more closely and the need for an on-board battery pack can be eliminated altogether. Using signals travelling back and forth between the surface of the well and the rotary drilling ~~unit~~ apparatus 10, the ~~unit~~ apparatus can be operated to maximize its flexibility. Additionally, because an ample amount of information can be easily transmitted back and forth in the wired pipe, various sensors 98 can be disposed on the rotatable steering ~~unit~~ apparatus 10 to measure the position and direction of the ~~unit~~ apparatus 10 in the earth. For example, conditions such as temperature, pressure in the wellbore and formation characteristics around the drill bit 78 can be

measured. Additionally, the content and chemical characteristics of production fluid and /or drilling fluid used in the drilling operation can be measured.

[0047] Yet another drilling component that can benefit from real time signaling and power, is a thruster 95, shown in Figures 11A and 11B. A thruster 95 is typically disposed above a drill bit 78 in a drill~~ing~~ string 75 and is particularly useful in developing axial force in a downward direction when it becomes difficult to successfully apply force from the surface of the well. For example, in highly deviated wells, the trajectory of the wellbore can result in a reduction of axial force placed on the drill bit 78. Installing a thruster 95 near the drill bit 78 can solve the problem. A thruster 95 is a telescopic tool which includes a fluid actuated piston sleeve (not shown). The piston sleeve can be extended outwards and in doing so can supply needed axial force to an adjacent drill bit 78. When the force has been utilized by the drill bit 78, the drill string 75 is moved downwards in the wellbore and the sleeve is retracted. Thereafter, the sleeve can be re-extended to provide an additional amount of axial force. Various other devices operated ~~by hydraulics~~ hydraulically or mechanically can also be utilized to generate supplemental force and can make use of the invention.[[.]]

[0049] Yet another component used to facilitate drilling and automatable with the use of wired pipe is a drilling hammer 96, shown in Figures 11A and 11B. Drilling hammers typically operate with a stroke of several feet and jar a pipe and drill bit into the earth. By automating the operation of the drilling hammer 96, its use could be tailored to particular wellbore and formation conditions.

[0050] Another component typically found in a drill string that can benefit from high-speed transfer of data is a stabilizer 97, shown in Figures 11A and 11B. A stabilizer is typically disposed in a drill string and, like a centralizer, includes at least three outwardly extending fin members which serve to center the drill string in the borehole and provide a bearing surface to the string. Stabilizers are especially important in directional drilling because they retain the drill string in a coaxial position with respect to the borehole and assist in directing a drill bit therebelow at a desired angle. Furthermore, the gage relationship between the borehole and stabilizing elements can be monitored and controlled. Much like the rotary drilling unit discussed herein, the fin members (not shown) of the stabilizer 97 could be automated to extend or retract individually in order to more exactly position the drill

string 75 in the wellbore. By using a combination of sensors and actuation components, the stabilizer 97 could become an interactive part of a drilling system and be operated in an automated fashion.

[0051] Another component often found in a drilling string is a vibrator 99, shown in Figures 11A and 11B. The vibrators 99 are disposed near the drill bit 78 and operate to change the mode of vibration created by the drill bit 78 to a vibration that is not resonant. By removing the resonance from the drill bit 78, damage to other downhole components can be avoided. By automating the vibrator 99, its operation can be controlled and its own vibratory characteristics can be changed as needed based upon the vibration characteristics of the drill bit 78. By monitoring vibration of the drill bit 78 from the surface of the well, the vibration of the vibrator 99 can be adjusted to take full advantage to its ability to affect the mode of vibration in the wellbore.